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PUBLIC UTILITIES COMMISSION

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August 24, 2009

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building, 1st Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0274 – Decoupling Proceeding
Hawaiian Electric Companies' Responses to Information Requests

Enclosed for filing are the Hawaiian Electric Companies'[1] responses to the July 15, 2009 post-hearing information requests ("IRs"), PUC-IR-56 through PUC-IR-63,[2] prepared by the Commission's consultant, National Regulatory Research Institute, in this proceeding.[3]

Very truly yours,

Enclosures

cc: Division of Consumer Advocacy
Hawaii Renewable Energy Alliance
Haiku Design and Analysis
Hawaii Holdings, LLC, dba First Wind Hawaii
Department of Business, Economic Development, and Tourism
Hawaii Solar Energy Association
Blue Planet Foundation

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[1] The "Hawaiian Electric Companies" or "Companies" are Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Limited.

[2] For reference purposes, the Companies have renumbered PUC-IR-7 through PUC-IR-14 as PUC-IR-56 through PUC-IR-63, to follow in sequential order from previously submitted IRs.

[3] On August 7, 2009, the Commission approved the Companies' request for an extension of time to August 24, 2009, for the Parties to respond to these IRs.

PUC-IR-56

Please discuss the success and failures of decoupling in other jurisdictions (e.g., Maine).

HECO Companies Response:

Maine Experience

As discussed further below in the "Other Repercussions" section of our response, the traditional trueup approach to decoupling stabilizes customer *bills* but this means that *rates* are somewhat less stable. Unwelcome rate increases can therefore occur during a *prolonged* recession since rates will rise after the first year of the recession even though the economy has not yet rebounded. While this is a disadvantage of the proposed mechanism, it should be recognized that rates can rise in the later years of a prolonged recession under traditional regulation as well.

In the early 1990s, rate increases due to decoupling during a recession led Maine's PUC to suspend a pilot decoupling trueup plan for Central Maine Power ("CMP") shortly before its sunset date. The size of the revenue shortfall was exacerbated by mild weather. Other conditions were also putting pressure on rates, including a decision by the Securities & Exchange Commission mandating that large accruals be recovered within two years; fuel and seasonal rate adjustments; and a change in rate design that apportioned a larger share of fixed costs to residential customers. Residential and business revenues were not subject to separate decoupling mechanisms. This combination of factors increased rates for some customers by more than 50%.

Since the recession in Maine was prolonged, it is likely that rates would have risen anyways, due to one or more conventional rate cases, in the absence of the decoupling plan. The CMP plan involved an RPC freeze, which is not a broad-based RAM. The Company therefore reserved the right to file a rate case during the decoupling plan and in fact did so. A withdrawal of the rate case was part of a stipulation under which CMP was permitted to recoup its revenue shortfalls under the decoupling plan.

Therefore, the suspension of the CMP decoupling pilot should not be interpreted as an indication that decoupling cannot succeed when the local economy is less than robust. Instead, the experiment in Maine was ended due to a juxtaposition of political and economic forces, only one of which was the rate hike resulting from the sales decoupling mechanism in a period of economic recession.

The situation in Hawaii differs from that in Maine, in that no Security and Exchange Commission mandate for reporting accruals is expected; a significant design change that transfers the recovery of fixed costs between customer classes is not on the horizon; and the HECO Companies and the Consumer Advocate have jointly proposed separate residential and commercial/industrial revenue balancing account surcharge mechanisms

Framework for Discussion

Before continuing the discussion it will prove useful to consider what kind of evidence of successes or failures would be dispositive.

1. Most of the cost of a utility's base rate inputs is fixed in the short run with respect to system use. A large share of this cost is nonetheless typically recovered through volumetric (demand and energy) charges. These realities provide the utility with disincentives to effectively promote demand-side management ("DSM") and development of customer-sited renewable resources because these activities discourage system use.
2. There are many ways that utilities can promote efficient use of their systems. These include
    - Utility energy efficiency ("EE") programs

- Utility policies on distributed generation (*e.g.* net metering, feed in tariffs, & connections)
- Rate design
- Support for government policies outside the regulatory arena that promote DSM and customer-sited renewables (*e.g.* appliance efficiency standards, building codes, funding for independent EE program administrators, and solar rebates)
- Other promotional measures

A company can earn a high ranking with respect to one approach but undermine its effect on system use efficiency due to a low ranking with respect to another approach. For example, a company can have a large appliance rebate program but only a modest overall effect on EE if it opposes improved appliance efficiency standards.

3. Measures to decouple a utility's earnings from usage charges can remove the disincentives to promote efficient system use. It is desirable for the decoupling mechanism to insulate earnings from the full range of efforts to promote efficient system use. The Oregon PUC, in approving a decoupling trueup mechanism for Portland General Electric ("PGE") in 1995, stated that "because decoupling separates profits from fluctuating sales levels, regardless of the cause of the changed sales, it addresses efficiency impacts resulting from *all* affects, including rate design, all utility-sponsored demand-side management activities, and all energy efficiency measures."[1]
4. The fact that *utility* EE programs are not the only way to encourage efficient system use is pertinent to stakeholders in Hawaii since most EE programs in Hawaii have transitioned to an independent public benefit funds (PBF) Administrator. One gauge of the importance of the

[1] OR95-0322, March 1995, p. 15.

other avenues for promoting efficient system use is a decoupling trueup plan *of some form* is currently operational in *five* states (NY, NJ, OR, WI, VT) in which most EE programs are independently administered.

State	EE Administrator	Utilities w/Decoupling True Up Plans
NJ	Clean Energy Program	New Jersey Natural Gas South Jersey Gas
NY	NYSERDA	Central Hudson (gas & electric) Consolidated Edison of NY (gas & electric) National Fuel Gas Niagara Mohawk (gas) Orange & Rockland (gas & electric)
OR	Energy Trust of Oregon	Cascade Natural Gas Northwest Natural Gas Portland General Electric ("PGE")
VT	Efficiency Vermont	Central Vermont Public Service[2] Green Mountain Power Vermont Gas Systems
WI	Clean Energy Wisconsin	Wisconsin Public Service (gas & electric)

The Oregon PUC stated, in its order approving a second decoupling plan for PGE this year, that

> While the parties do not disagree that relying on volumetric charges to recover fixed costs creates a disincentive to promote energy efficiency, they contend that decoupling is unnecessary because, with the [Energy Trust of Oregon ("ETO")] running energy efficiency programs in PGE's service territory, the Company has limited influence over customers' energy efficiency decisions. We find this position unpersuasive, because

[2] The Vermont utilities do not use balancing accounts to force revenues to track revenue requirements. For this reason, some Vermont decoupling plans were not mentioned in all of our previous precedent reviews. However, the revenue requirement of each utility in Vermont is reset each year using a *revenue* adjustment mechanism and rates are set to recover the revenue requirement using forecasted billing determinants. This is tantamount to a partial trueup. Vermont was listed as a decoupling state in an April 2007 HCEI presentation, "Selected Clean Energy Policies in Five Leading States," prepared by Catherine Murray of the Regulatory Assistance Project.

> PGE does have the ability to influence individual customers through direct contacts and referrals to the ETO. PGE is also able to affect usage in other ways, including how aggressively it pursues distributed generation and on-site solar installations; whether its supports improvements to building codes; or whether it provides timely, useful information to customers on energy efficiency programs. We expect energy efficiency and on-site power generation will have an increasing role in meeting energy needs, underscoring the need for appropriate incentives for PGE.[3]

5. There are four established approaches to revenue decoupling:

    1. annual rate cases;
    2. lost margin recovery mechanisms;
    3. straight fixed variable ("SFV") pricing; and
    4. the true up of revenues to revenue requirements.

    These approaches should be evaluated with regard to the following criteria:

    1. Administrative simplicity;
    2. Encouragement of the various ways in which utilities can promote efficient system use; and
    3. Other repercussions.

    We consider each of these criteria in turn.

Administrative Simplicity

In the matter of administrative efficiency, the various approaches to decoupling are as follows.

1. Annual rate cases
2. Lost margin recovery

[3] UE 197, January 2009, p. 27

3. SFV pricing
4. Revenue trueups

The administrative cost of annual rate cases is well known to be high, particularly in a jurisdiction with multiple utilities. Annual rate cases also have other detrimental effects such as a tendency to erode utility operating performance due to weak incentives and the distraction of senior management from the company's basic business. This approach to decoupling may therefore be deemed prohibitively expensive. In the Companies' response to PUC-IR-23, a comparison of costs between traditional rate cases and the sales decoupling mechanism include in the Companies' January 30, 2009 proposal. Attachment 1 to PUC-IR-23 response shows an annual amortization cost ranging from $510,000 to $774,000 under the traditional rate case method, while Attachment 2 to PUC-IR-23 response, shows that under the January 30, 2009 decoupling proposal, the range is from $37,000 to $93,000.

Lost margins are difficult to estimate accurately due to the numerous business conditions that affect a customer's use of the utility system. For this reason, the lost margin approach is generally applied only to utility DSM programs and does not effect full decoupling. This approach will therefore not remove the disincentive for a utility to encourage efficient system use in other ways. It is reasonable then to consider both annual rate cases and the lost margin approaches to decoupling to be impractical.

The trueup approach to decoupling involves monthly, quarterly, or annual trueups. These unambiguously add to the cost of regulation. However, the cost of a decoupling trueup is not much different than the cost of other widely used trackers such as fuel adjustment clauses ("FACs"). The Oregon PUC stated in the order quoted above approving a decoupling trueup plan for PGE that "it is a relatively simple mechanism to remove a variety of perverse incentives inherent in the existing structure of rate regulation and it has low administrative costs."[4] The cost of the trueup approach can be reduced with multiyear revenue adjustment mechanisms ("RAMs") that increase the period between rate cases.

SFV pricing involves the lowest administrative cost amongst the four established approaches to decoupling. Once SFV prices are established there is no need for supplemental annual rate adjustments of any kind to effect decoupling. However, SFV pricing does not provide the basis for utilities to commit to multiyear rate plans under normal operating conditions. Hence, a multiyear decoupling true up plan featuring a broad-based RAM can potentially be achieved with lower *overall* regulatory cost.

Scale and Effectiveness of EE Programs

Evidence on the scale of EE programs must be treated with caution in an appraisal of alternative decoupling mechanisms. The scale of *utility* programs depends, in addition to the decoupling mechanism chosen, on other conditions such as the budgets approved for EE programs, program cost recovery provisions, the character of supplemental incentives for utility EE programs, and whether or not some EE programs are pursued by independent agencies. We could, instead, consider the scale of programs irrespective of whether they are offered by utilities. The scale of independent EE programs is relevant to an appraisal of decoupling since it may, for instance, reflect the degree to which a utility resists a large program that is run by an independent agency. This is not a minor matter since independent programs are often funded out of utility rates.

The American Council for an Energy Efficient Economy ("ACEEE") recently issued a study that ranks states in terms of the overall scale and effectiveness of EE programs.[5] Five

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[4] Order No. 95-322 March 1995, p. 4.

states in which most EE programs were run by independent agencies were considered in the study along with states in which most programs were undertaken by utilities. Here are some salient results.

1. California had the number one ranking in the survey for both natural gas and electric EE programs.
2. Including California, six of the seven states with the highest-rated electric EE programs (CA, CT, WI, NY, OR, and VT) now have at least one electric utility decoupling trueup plan. However, five of these states (CT, WI, NY, OR, and VT) have only recently instituted (or reinstituted) decoupling and most have not yet extended it to all utilities. The other state in the top 7, Massachusetts, is in the process of implementing decoupling for all electric utilities.
3. The state of Maine has an independent DSM program administrator but does *not* have decoupling. Maine was not ranked in the ACEEE top 14.
4. Including California, seven of the ten states with the highest-rated *gas* EE programs (CA, WI, NY, OR, NJ, VT, WA) have at least one decoupling trueup program for a gas utility. However, five of these states (WI, NY, NJ, VT, WA) have only recently instituted (or reinstituted) decoupling and several of these have not yet extended it to all utilities. Of the other three states in the top 10, Massachusetts and Connecticut are in the process of implementing decoupling for all utilities.

Rate Design

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[5] Martin Kushler, Dan York, and Patti Witte, "Meeting Aggressive New State Goals for Utility-Sector Energy Efficiency: Examining Key Factors Associated With High Savings," ACEEE Report No. U091, March 2009.

The design of rates is a function typically retained by the utility whether or not it is responsible for administering EE programs. Rate design can have a critically important impact on customer incentives for efficient system use, including EE, peak system use, and the development of solar and other renewable resources. Conservation and customer-sited DG are generally encouraged by high volumetric charges, which reduce the pay back period for investments. Usage charges that vary by time of use ("TOU") discourage peak system use and encourage development of customer-sited solar resources. However, peak load pricing discourages EE to the extent that usage charges are lower than flat rates in most hours of use.

Recall, now, that there are two practical approaches to decoupling because annual rate cases and lost margin adjustments involve excessive regulatory cost. Of the two practical approaches, the true-up approach seems to be superior *on paper*. While it is often argued that SFV pricing encourages efficient system use there are persuasive counterarguments to this contention. For example, system peak demand is widely used in regulation to allocate utility revenue requirements between customer classes. Residential customers typically have low load factors and account for a sizable share of peak system use. By one means or another, large volume residential customers should therefore typically pay more for system use than small volume customers such as apartment dwellers. Peak load pricing also encourages economical use of specialized peak load facilities. Since traditional residential meters do not record peak demand, however, SFV pricing for residential customers conventionally involves uniform flat, low volumetric charges and uniform, high minimum bills.

The value of rate design in promoting efficient choices has been recognized in writing by two of the state of Hawaii's HCEI advisors.

- In its 2008 report to the Minnesota Public Utilities Commission, the Regulatory Assistance Project ("RAP") states that

> a zero or minimum customer charge allows the bulk of a utility's revenue requirement to be reflected in the per-unit volumetric rate. This serves the function of better aligning the rate for incremental service with long-run incremental costs, including incremental environmental costs.[6]

- The National Regulatory Research Institute (NRRI) writes that

> The problem with SFV is that it reduces the variable charge to short-term variable cost, which is likely to be lower than the economically efficient level of long-term marginal cost, leading to overconsumption.[7]

The natural gas pipeline industry of the United States provides an illustration of how SFV pricing can boost utility system use. The Federal Energy Regulatory Commission instituted SFV pricing in the interstate natural gas industry in a largely successful effort to promote competitive wholesale gas markets. System use was stimulated, including the growing use of gas in power generation.

The problem with efficient rate designs is that they generally increase the risk of fixed cost recovery between rate cases. Inverted block rates, for instance, slow demand growth and enhance the sensitivity of revenue to fluctuations in demand drivers such as weather, fossil fuel prices, and recessions. NRRI acknowledges this problem, commenting that

> Marginal cost pricing is difficult to achieve when revenue requirements are based on embedded costs. State commissions have used inverted block rates to try to achieve this goal, but those rates aggravate the decoupling problem discussed above, because the movement towards marginal cost pricing is accomplished by shifting more of the embedded fixed cost to marginal charges in the inverted block rates.[8]

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[6] Wayne Shirley, Jim Lazar, and Frederick Weston, "Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission," June 2008, p. 18.
[7] David Magnus Boonin, "A Rate Design to Encourage Energy Efficiency and Reduce Revenue Requirements," National Regulatory Research Institute, 2008.
[8] *Ibid*, p. 10.

NRRI proposes to address this problem via a combination of SFV pricing and revenue-neutral energy efficiency feebates. This idea, never tried, may bear fruit down the road. However, the problem can be addressed *today* by a combination of efficient *utility* rate designs and the trueup approach to decoupling.

The ability of decoupling trueups to facilitate efficient pricing has long been recognized. David Moskovitz, a founder of the Regulatory Assistance Project, was an early proponent of decoupling. In a 1992 paper, he addressed the relationship between decoupling and efficient rates.

> Getting prices "right" is clearly an important element of least-cost planning. Unfortunately, the right prices are often opposed by utilities, due to the impact of those prices on earning stability.
>
> Inverted block rates and time-of-use rates may provide better price signals to consumers than declining block or flat rates. But these price structures are opposed by utilities because of the risk that customer response to the price signals will significantly reduce utility revenues and earnings. With time-of-use rates, for example, customers respond to high "on peak" rates by investing more heavily in energy efficiency or shifting electricity use from on peak to off peak periods. These responses to better price signals result in substantially diminished utility earnings...
>
> Decoupling holds utilities harmless from revenue losses resulting from consumer response to better prices and as a result aids in the effort to improve pricing.[9]

RAP states in its report to the Minnesota Public Utilities Commission that

> Decoupling should remove traditional utility objections to electric and natural gas rate designs which encourage energy conservation, voluntary curtailment, and peak load management.[10]

The report goes on to say that

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[9] David Moskovitz, Cheryl Harrington, and Tom Austin, "Decoupling vs. Lost Revenues: Regulatory Considerations," Regulatory Assistance Project, 1992.
[10] Wayne Shirley *et al*, *op cit*. p. 16.

> Revenue stability needs of the company can conflict with principles of cost causation as they relate to customers...To the extent that utility fixed costs are associated with peak demand (peaking resources, transmission capacity, natural gas storage and LNG facilities) and those capacity costs are allocated exclusively to excess use in winter and summer months, the cost to consumers of excess usage is dramatically higher than the cost of base usage. A steeply inverted block rate design, such as those used by PG&E, correctly associates the cost of seldom-used capacity with the (infrequent) usage that requires that capacity. While this is arguably "fair", doing so can result in serious revenue stability issues for the utility. Decoupling is one way to address the revenue stability issue for the utility, without introducing rate design elements such as high fixed monthly charges, in the form of a Straight Fixed/Variable rate design, that remove the appropriate price signals to consumers.[11]

An important point to note in this regard is that containment of the risk of efficient utility pricing will be greater to the extent that earnings are decoupled with respect to *all* sources of demand volatility, including recessions and weather fluctuations. Customers are asked to pay the same bill for system use during a recession that they would during the ensuing recovery so that the utility can offer rate designs that encourage customers to make the right choices concerning EE and renewable resource development. The target ROE may need to be raised in the absence of full decoupling.

Having demonstrated that the trueup approach to decoupling should remove disincentives to the design of utility rates that encourage efficient system use, we now turn to a consideration of whether such successes have occurred *in practice*. For example, have utilities operating under the trueup approach to decoupling been able to maintain or even enhance inverted block rates despite a high level of DSM effort? Here is some evidence of success.

California

[11] *Ibid*, p. 17.

Decoupling for California's electric utilities extends to all customer classes. TOU pricing was implemented for most large volume customers around the time that decoupling was first introduced in the early 1980s. TOU pricing for residential customers was also available in the 1980s. Inverted block rates were mandated for small volume customers without TOU meters in the 1970s. The decision approving the first decoupling plan for Southern California Edison stated that "the adoption of a revenue adjustment mechanism is effective in eliminating disincentives for the utility to promote the conservation *and rate design policies* enunciated by this Commission [italics added]."[12]

The turn of the century power crisis in California heightened the interest of state regulators in peak load pricing. TOU pricing became mandatory for all customers with maximum demand greater than 200 kW. More ambitious peak load pricing programs were instituted soon after the reimposition of decoupling. Pursuant to D. 03-03-036, a Statewide Pricing Pilot has tested the impact of TOU and critical peak pricing tariffs on residential and commercial customer usage patterns. Many customers with solar photovoltaic ("PV") facilities have participated in TOU pilots. Pursuant to the 2003 Vision Statement in D.03-06-032 and Energy Action Plan II in 2005, a more sweeping program was instituted to go beyond TOU pricing to make dynamic rate designs available to all customers using AMI, beginning with large volume customers. A remarkable number of peak load pricing options are now available to non-residential customers.

All three major California electric utilities are in the process of implementing systemwide AMI. Pending the completion of this effort, small volume customers face inverted block rates for base rate inputs. For example, a typical residential customer of PG&E's *distribution* services

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[12] D. 82-12-055 (1982) p. 17.

faces a low $3.58 minimal monthly bill and 5 tiers of volumetric charges ranging from $ 0.037/kWh for the lowest tier to $ 0.16/kWh for the highest tier. Remarkably, residential TOU prices also involve inverted block rates.

California was also the early bird in the implementation of decoupling for natural gas utilities. Decoupling was instituted in the late 1970's. Helping gas companies cope with the risk of inverted block rates was an important motivation for the decoupling plan. Inverted block rates are still common for California gas utilities and are otherwise rare in the US gas distribution industry.

Consolidated Edison (2008-)

Con Ed's decoupling plan extends to most service classes. At the inception of decoupling, the company already offered voluntary time of use rates to most customer classes and mandatory TOU rates to some classes. Other customers paid inverted block rates. For example, in summer the residential TOU energy delivery charge was 25 cents on peak and 0.81 cents off peak. All other residential customers paid low customer charges and seasonal inverted multitier volumetric rates with a gradual inversion. In the 2007 filing in which decoupling was approved, Con Ed successfully proposed to extend mandatory hourly pricing to customers with maximum demand greater than 500 kW. The company sells transmission congestion credits and obtains substantial revenue from the New York ISO. A $150 million credit was factored into the approved 2008 revenue requirement. The Company has proposed systemwide deployment of AMI.

Idaho Power (2007-2009)

The IPC decoupling plan pertains only to residential and small general service customers. The company had TOU and critical peak pricing pilots underway for residential customers participating in an AMI pilot before the start of decoupling. No expansion of the pilot program has occurred under decoupling. However, in 2009, the Commission approved a three tier, year around inverted block rate structure for most residential customers.[13] The Commission also approved year round inverted block rates for the small general service customers covered by decoupling. Staff identified these tiered rates as a "reasonable surrogate for time of use rates that send customers a message to use energy efficiently." The company has proposed a systemwide deployment of AMI beginning in 2009.

<u>Portland General Electric</u> (2009-2011)

The decoupling plan of PGE doesn't extend to the company's largest customers. At the inception of decoupling, TOU pricing was an option for small business customers but not residential customers. However, residential customers faced inverted block rates. The company commented in its rate design testimony that "absent our decoupling proposal, we would advocate for higher customer charges to reduce the impact of recovering fixed distribution costs on a volumetric basis."[14]

Despite an increasingly peaked load profile, PGE didn't propose major rate design innovations in the filing and successively opposed a proposal by commission staff to make some modest pricing reforms. However, the company did agree to a generic hearing to address rate design issues and is proposing extensive AMI deployment.

<u>Wisconsin Public Service (2008-2012)</u>

Decoupling covers residential and most commercial customers but not large industrial customers. WPS offered TOU pricing to some residential and business customers before the

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[13] Most residential customers previously faced a two tier increasing block rate structure with a very gradual inversion in the summertime.

[14] Direct Testimony of Doug Kuns and Marc Cody in UE 197, February 2008.

institution of decoupling in 2008. TOU rate classes will continue. A reduction in residential customer charges (from $8.40 to $5.70 for single phase service) was part of the Company's settlement with the Citizens Utility Board. The decoupling plan also includes the development and implementation of three community based pilot programs that include "innovative rate offerings that increase opportunities for customers to use energy more efficiently." One of these programs will include AMI.

Hawaii

Even though the Commission has not approved revenue decoupling for the HECO Companies, it is noteworthy that the Energy Agreement between the HECO Companies and the Consumer Advocate commits the HECO Companies to implement the previously proposed inverted block rate for residential customers. It also requires that mandatory TOU pricing be applied to all C&I customers once AMI has been installed.

Conclusions

Inverted block rates and peak load pricing are remarkably common for electric utilities operating under decoupling plans. This is consistent with the notion that decoupling encourages rate design innovation that can improve efficient system use. While the pervasiveness of peakload pricing is limited to the availability of AMI, all utilities surveyed seem interested in widespread installation of AMI.

Appliance Standards etc.

A utility operating without full decoupling has incentives between rate cases to resist changes in appliance standards, building codes, and other public policies that encourage EE. Stringent standards in states with decoupling may reflect the acquiescence or active support of utilities. Decoupling agreements sometimes contain utility commitments to support efficiency standards. Here are recent some examples.

California

California has been a national leader in the establishment of policies outside the regulatory arena that promote energy efficiency. The state has a separate commission [the California Energy Commission ("CEC")] to monitor and regulate key aspects of the energy economy. This includes the establishment and enforcement of EE standards for buildings and appliances. A CEC study has found that conservation due to appliance and energy efficiency standards has grown substantially since the institution of decoupling and now accounts for more than half of the accumulated energy savings since 1980. In the aftermath of the power crisis, and following the resumption of decoupling pursuant to a 2001 statute, California instituted an *Energy Action Plan* in 2003 that has been periodically updated. The plan features aggressive new measures to promote energy efficiency and demand response.

Wisconsin Public Service

WPS agreed in its decoupling settlement with the Citizens Utility Board to specific steps to support the adoption and implementation of certain recommendations of the Governor's Global Warming Task Force addressing

- Residential and Commercial Energy Efficient Building Codes
- State Appliance Efficiency Standards
- Nonregulated Fuels Efficiency and Conservation.

Solar Policies

California

The Network for Energy Choices released a study in 2009 that ranked states on policies to promote solar energy.[15] The focus of the study was net metering policy and interconnection standards. In this study, California ranked only seventh, garnering a "B grade" for both net metering and connections.

However, the study does not consider subsidies and other California policies that promote development of customer-sited solar resources. Salient in this regard is the California Solar Initiative. Customer-sited photovoltaic (PV) generation capacity has grown rapidly in the state in recent years, pushing against current net metering limits. The Solar Water Heater and Heating Efficiency Act of 2007 has introduced a new rebate program for solar water heating. All three large California utilities are now required to offer feed in tariffs on an experimental basis. The companies have opposed an expansion of the net metering cap until a study of its effects is completed.

Dr. Lowry contacted authors of the *Freeing the Grid* study to ask how California ranked with regard to its overall support for solar energy. One (Rusty Haynes) responded by email that

> CA has been at the top of the U.S. state solar heap for many years, primarily due to strong public policy efforts and funding commitments. CA blows the rest of the states away in terms of number and capacity of installed solar-energy systems. There is no publication that rates states on overall policy efforts to promote solar. But if there were, and especially if the study took into account policies implemented during the last 10 years, CA would very likely take the top slot. Other states are catching up, but this will take a long time.

[15] James Rose *et al*, *Freeing the Grid: Best and Worst Practices in State Net Metering Policies and Interconnection Standards*, Network for New Energy Choices, October 2008.

Another (Adam Browning) responded by email that "...for subsidies, I'd say that CA is far beyond any other state in the nation."

Hawaii

Even though the Commission has not approved revenue decoupling for the HECO Companies, it is noteworthy that the Energy Agreement between the HECO Companies and the Consumer Advocate commits the HECO Companies to seek support for the development of customer sited solar resources. These include support for a continuation of solar water heating tax rebates, a solar water heating "pay as you save" program, feed-in tariffs, net metering at time of use pricing, and a PV Host program.

Other Measures

Other measures that utilities can take to promote efficient system use include advertising, bill inserts, and cooperation with the independent energy administrator.

Few studies have endeavored to examine the possible effects of decoupling on these measures. One of the best was an independent appraisal of the decoupling plan, called the Distribution Margin Normalization ("DMN"), of Northwest Natural Gas in Oregon. The authors, who recommended the continuation of decoupling, state in a summary comment that

> We have been impressed by the breadth of support that DMN has received. The Energy Trust of Oregon reports that NW Natural has been successful in creating a good working relationship with the Energy Trust, and that NW Natural's efforts to promote energy efficiency effectively complement their own efforts. HVAC distributors believe that NW Natural's marketing efforts, in conjunction with its relationships with consumers, distributors, and the Energy Trust have helped increase sales of high-efficiency furnaces to the point where Oregon has the highest share of high-efficiency furnaces in the nation (as a percentage of new furnace sales). The Citizens' Utility Board of Oregon, the Northwest Energy Coalition and a number of CAP agencies believe that the Public Purposes Funding established in conjunction with the DMN is beneficial for consumers. The Natural Resources Defense Council and American

Gas Association released a joint statement regarding the positive environmental effects of decoupling, specifically citing NW Natural's experience as an example of the positive outcomes that decoupling can yield.[16]

Other Repercussions

Decoupling Trueups

Rate stability was an issue in Maine under the CMP decoupling pilot in the 1990s. This was addressed above. A study of early California decoupling plans reveals that price volatility was not pronounced.[17] Another study, prepared for the National Resources Defense Council, has reached the same finding for contemporary decoupling plans.[18] In the latter study, rate adjustments were typically less than 2% and only rarely in excess of 5%. Rate adjustments produced by purchased gas adjustment and fuel and purchased power adjustment clauses tend to be much larger. Both of these studies found that adjustments were positive nearly as often as they were negative.

The rate volatility problem is nonetheless of concern to some regulators and can be contained by several means. One is to exclude from decoupling the impact of certain kinds of demand fluctuations such as weather. This approach has been popular in Oregon, where weather fluctuations have been excluded from several decoupling plans, but involves complex statistical normalization calculations. Another means of reducing rate volatility is to limit the size of rate or revenue requirements that can be made in a given year. "Soft" caps permit utilities to defer for later recovery any account balances not recovered due to the cap. "Hard" caps do not.

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[16] Daniel Hanson and Steve Braithwait, "A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005.
[17] Joseph Eto, Steven Stoft, and Timothy Belden, *The Theory and Practice of Decoupling*, Lawrence Berkeley Laboratory paper LBL-34555 UC-350, 1994.
[18] Pamela Lesh, "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review," June 2009.

Companies operating under soft caps include Delmarva Power & Light (MD).[19] Companies operating under hard caps include Wisconsin Public Service.

SFV Pricing

A negative repercussion of SFV pricing is high minimum bills for small volume residential customers. Sharp increases in the bills of small volume customers are expected in Ohio where SFV pricing is being rapidly implemented by several gas utilities. The need for high minimum bills should fall wherever AMI is installed for all residential customers since there is then no need for a utility operating under a decoupling true up mechanism to assign costs attributable to peak demand to customer charges.

Conclusions

This discussion permits us to draw a number of conclusions about decoupling successes and failures.

- Utilities have at their disposal a wide range of measures to promote efficient use of their systems. These include rate design and support for improved building codes and appliance efficiency standards as well as utility-administered EE programs.
- Decoupling is most effective at promoting efficient use when it removes disincentives to use all of the "arrows in the quiver."
- SFV pricing and the traditional trueup approach to decoupling are the only established approaches that are practical for encouraging a wide range of promotional activities.

[19] The Maryland Commission stated in its order approving a 10% soft cap in revenue adjustment for Delmarva that it "finds that limiting the amount of revenues that the Company will recover from customers in a given month is a reasonable accommodation of the competing concerns for insulating the Company from revenue variability and insulating the customer from above average or below average usage due to forces beyond its control." Order No. 81518, July 2007 pp. 50-51.

- Of these two, SFV pricing has a lower administrative cost but can prohibit utilities from designing their base rates in ways that best promote efficient use of their systems. The administrative cost of decoupling trueups is, meanwhile, not markedly different from that of a fuel adjustment clause or other common trackers.
- The true up approach to decoupling is thus the only established approach to full decoupling that is both practical and encourages the full range of promotional activities. These advantages are noteworthy "successes" and help to explain why the trueup approach to decoupling is used in some form in every state that has an independent program administrator.
- California provides an impressive record as to the potential benefits of full decoupling using the trueup approach. This state, which has the lengthiest experience with this decoupling approach, is a national leader with respect not only to gas and electric EE programs but to rate designs, appliance efficiency standards and building codes, and policies to promote development of customer-sited solar resources.

PUC-IR-57

Please discuss the pros and cons of implementing the revenue enhancements discussed at each of 3a (reliability investments), b (customer addition investments), c (Act 155 compliance O&M), and d (HECO's proposed O&M cost escalator) of the Commission's post-hearing IRs.

HECO Companies Response:

The design of the revenue adjustment mechanism ("RAM") is one of the key issues that the Commission faces in this proceeding. Under revenue decoupling, revenue growth is limited to revenue *requirement* growth. Decoupling would require rates to *fall* if the revenue requirement were fixed but there was growth in the volume of sales and other billing determinants.

Stakeholders accustomed to regulating utility *rates* can have a hard time understanding why the revenue requirement needs to grow over time. The trend in a utility's rates depends on the trend in its *unit* cost – the cost per unit of billing determinants such as kWh, kW, and the number of customers served. Unit cost tends to grow more slowly than the growth in total cost by the growth in billing determinants. Suppose, for example, that a utility collected all revenue from a uniform volumetric charge. If total cost grew by 1% and the volume grew by 1%, there would be no need for the rate to grow at all[1]. In this example, a rate freeze would be just and reasonable but a revenue requirement freeze would not be. Under favorable operating conditions, the *unit* cost of a utility can grow quite slowly, providing the basis for a multiyear rate freeze. But *total cost* almost always grows.

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[1] To demonstrate this contention, let $\text{Unit Cost}_t = \text{Cost}_t/\text{Volume}_t$. The logarithmic growth rate of unit cost is then $\ln(\text{Unit Cost}_t/ \text{Unit Cost}_{t-1}) = \ln[(\text{Cost}_t/\text{Volume}_t)/(\text{Cost}_{t-1}/\text{Volume}_{t-1})]$
$= \ln[(\text{Cost}_t/ \text{Cost}_{t-1})/(\text{Volume}_t /\text{Volume}_{t-1})]= \ln(\text{Cost}_t/ \text{Cost}_{t-1})+\ln(\text{Volume}_t /\text{Volume}_{t-1})$. The growth rate of unit cost is thus the difference between the growth rates of cost and volume. If cost and volume both grow by 1%, unit cost growth is flat. It can be shown that this principle extends to multiple billing determinants.

Rate cases must therefore be held constantly under revenue decoupling if the revenue requirement isn't escalated automatically to reflect the cost impact of changing business conditions. The recent experience of Consolidated Edison in New York is illustrative. In a 2007 rate case decision, the company proposed a multi-year "stairstep" RAM but the decoupling plan was approved without any RAM. This has led the company to file rate cases in each successive year since the decoupling plan was approved[2]

Frequent rate cases by the three Hawaiian Electric Companies would be a costly distraction for the Commission, the Consumer Advocate, and the Hawaiian Electric Companies at a time when a number of HCEI initiative and other utility proceedings are before the Commission. Frequent rate cases would also undermine the operating performances of the companies by weakening performance incentives and distracting senior managers from their basic business.

The linkage between rate case frequency and utility performance incentives has been noted by NRRI and the Regulatory Assistance Project (RAP). NRRI stated that "price and revenue cap models try to increase the cost minimization incentive, relative to the cost-of-service model, by prolonging the period between rate cases and eliminating the profit cap."[3] Similarly, RAP lists the various benefits of a decoupling regime. RAP opines that "a well-designed decoupling plan (one that possibly allows for adjustments according to changes in short-term drivers such as numbers of customers, inflation, and productivity) could reduce the frequency of

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[2] To the best of our knowledge, Central Hudson Gas & Electric is the only other one of the sixteen electric utilities with a trueup decoupling mechanism to operate without a RAM. Their plan was approved this year on June 22 (Docket 08-E-0887). The company filed a new rate case on July 31 (Docket 09-E-0588).

[3] Scott Hempling and David Magnus Boonin, "Overview of Regulatory Incentives in the Context of Public Policy Goals." Prepared for the Colorado Public Utilities Commission. June 2008, p.12.

general rate cases."[4] RAP further elaborates that one of the benefits of a revenue cap is "management's greater focus on operational efficiency..., particularly one that has explicit adjustments for productivity growth over time."[5]

Frequent rate cases can be avoided under decoupling via the use of *broad-based* RAMs. These are RAMs that adjust the revenue requirement automatically for changes in several of the business conditions that drive cost growth. Noteworthy drivers of utility cost include

- Input price inflation
- Output (*e.g.* customer) growth
- Increased need for investments to promote reliability due, for instance, to increasing system age and/or increased reliance on intermittent power supplies from renewable resources
- Changes in policy such as the institution of Act 155.

The four "revenue enhancement tools" discussed in PUC–IR-52 are as follows.

- The first proposed tool would compensate the Companies for higher capital costs due to reliability investments. Investments of this type are expected to be made every year to allow the utilities to provide reliable service to their customers. As shown in the response to PUC-IR-52, this category of investment usually reflects the lion's share of the Companies' total capital budget. The method of recovery for these costs as proposed in the IR (the Companies' understanding of the recovery method is further discussed in the response to PUC-IR-61) is advantageous to the Companies since it allows the Companies to implement a surcharge on a quarterly basis, almost

[4] Wayne Shirley, et. al. "Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission. June 2008, p. 9.
[5] *op cit* p.10.

immediately after the plant is placed into service (practically speaking, there would be a lag of at least three months (one quarter) to aggregate and verify the plant that is placed into service, to calculate associated rate base components such as depreciation and ADIT, prepare the filing to the Commission, and implement the surcharge). Another advantage of the proposed method of recovery is that, by only including plant that is already placed into service as the basis for the surcharge, it addresses the potential concern that ratepayers would be paying for plant additions that are not yet used or useful.

- The second proposed tool would compensate the Companies for investments needed to serve additional customers. This would be especially welcome for HELCO and MECO, given their comparatively rapid customer growth. The advantages noted above for the reliability category of investment also apply to this revenue enhancement tool as well.
- The third proposed tool would compensate the Companies for extra O&M expenses occasioned by Act 155, which raises renewable portfolio standards for the Companies to levels that are remarkably high by national standards. The Companies understand this category of costs to be those that are not recovered from any other surcharges. There is no special provision for these O&M expenses in the Companies' proposal. A disadvantage of implementing this revenue enhancement is that, currently, there is no clear or consistent definition of Act 155 costs among the Companies. If this proposed tool were authorized by the Commission in the instant proceeding, there is a need for the Consumer Advocate and Commission to assist in determining what should constitute this category of costs. Additionally, because the Companies have

not historically tracked costs in this manner so new internal procedures would need to be developed and established so that Act 155 expenses (not recovered through other surcharges) are easily identified and gathered for reporting purposes.

- The fourth proposed tool is the O&M expense escalation formula proposed by the Consumer Advocate and the Hawaiian Electric Companies. This would compensate the Companies for the impact that a broad range of business conditions, including input price inflation and output (*e.g.* customer) growth have on O&M expenses. Along with the other provisions reflected in the Final Joint Statement of Position, the O&M expense RAM proposed by the Consumer Advocate and the Hawaiian Electric Companies is "a conservative approach to decoupling and . . ., to the extent possible, administratively efficient and contain ample safeguards to project the public interest against the potential for excessive rates, while not doing damage to the incentives for HECo. to operate the utility companies efficiently. . . . [It is] protective of the public interest, conservative in exposure rate payers would face to increasing revenue requirements, and designed in a way that would be administratively practical." (Panel Hearings, Volume I, page 94, lines 2-7 and 17-21.) The reasonableness of the proposed escalator is discussed at some length in Attachment 1 of this response. The discussion there relies on a discussion of principles for escalator design and the empirical research which are set forth in PEG's report on decoupling. (Refer to the *Revenue Decoupling for the Hawaiian Electric Companies* (revised February 3, 2009), Pacific Economics Group, LLC ("PEG").)

All four of these tools provide compensation for one or two cost drivers but none of them are individually sufficient to avoid frequent rate cases. A combination of the tools would, naturally, make an alternative RAM composed of them more compensatory. Tools a and b together come close to providing the needed capital cost escalation for a majority of the Companies' annual plant additions. However, tool c by itself is clearly deficient as an escalator of O&M expenses.

Also options a-c involve higher regulatory cost than the escalator proposed by the Consumer Advocate and the Hawaiian Electric Companies. Options a-c call for quarterly filings while the Consumer Advocate's and the Hawaiian Electric Companies' RAM proposal requires only an annual filing. The categorization of costs into groupings that have priority for regulators provides an effective incentive to the Companies with regards to the importance of investments and expenditures in those categories. For example, if the Commission were to adopt a RAM that provides inter-rate case recovery for reliability investments, the Companies would clearly focus its resources in the area of reliability. The unintended consequence is that there are other areas of focus which deserve attention and allotments from the Companies' limited resources that may be reduced as the result of the adopted RAM. For example, other areas that the Companies consider important include efforts to prepare the system grid for the introduction of additional renewable resources, transmission and distribution line extensions for new housing developments, and pollution abatement.

In conclusion, while the adoption of one of the revenue enhancement tools discussed above would provide the utilities with a clear understanding of the regulator's priorities, each tool alone would not achieve the same potential for reduction of rate case frequency that would be provided by the revenue decoupling proposal submitted by the Consumer Advocate and the Hawaiian Electric Companies, would insert a degree of subjectivity into the process (i.e., with regards to what is the definition of Act 155 costs) and may have unintended consequences with regards to expenditures and investments made by the utilities.

Option d, the O&M escalator in the *Joint Final Statement of Position of the HECO Companies and Consumer Advocate* ("final SOP"), filed May 11, 2009, merits further discussion. We begin by describing its basic components.

Each budget for salaries and wages would be escalated by the average growth in the HECO Companies' union wages, less a 0.76% X factor to account for productivity gains. The 0.76% figure was the X factor in the price cap indexes proposed by the HECO Companies in their 1999 performance-based ratemaking proposal. This figure was prepared by Dr. Mark Lowry of Pacific Economics Group, LLC ("PEG"), a noted authority on the design of attrition relief mechanisms who has testified on index research in more than a dozen rate filings. The 0.76% figure is based on a study of the input price and productivity trends of 125 vertically integrated U.S. electric utilities over lengthy sample periods ending in 1997. The data used in the study were all drawn from respected public sources such as the Federal Energy Regulatory Commission ("FERC") Form 1.

Each utility's budget for materials and services would be escalated by the inflation in the gross domestic product price index ("GDPPI"). The GDPPI is the federal government's featured measure of inflation in the prices of final goods and services. It is the most widely used inflation measure in U.S. attrition relief mechanisms because its broader coverage makes it more stable than the alternative consumer price index.

To appraise the reasonableness of the proposed mechanism it is useful to recall a basic result of index logic that Dr. Lowry discussed in his February decoupling discussion paper in this proceeding.[1] On page 19, Dr. Lowry notes that the trend in a company's O&M expenses equals the trend in the prices paid for O&M inputs less the trend in an O&M productivity index plus the trend in the number of customers served.

$$\text{trend Cost}^{O\&M} = \text{trend Input Prices}^{O\&M} - \text{trend Productivity}^{O\&M} + \text{trend Customers} \qquad [1]$$

The trend in a productivity index is the difference between the trends in an output index and an input quantity index. The output index used in formula [1] is the number of customers served.

[1] See Attachment 1 filed with "Corrections to the HECO Companies' Revenue Decoupling Proposal," by the HECO Companies on February 3, 2009.

Formula [1] provides the basis for a good O&M escalator, using a custom index of O&M input prices, an estimate of the recent historical O&M productivity trend, and the company's own customer growth. This general approach was considered in the report as Hybrid III (Full Indexation using PEG Custom Input Price Index) and was shown in Table 9 to be almost exactly compensatory for all the HECO Companies on average in a historical simulation over the 1996-2007 period.

While the O&M escalators used in approved hybrid RAMs rarely have the structure of formula [1], the formula is still useful for appraising alternative escalators. For example, most of the hybrid RAMs approved for use in California have escalated O&M expenses using only indexes of electric utility O&M input prices from Global Insight. It can be shown that this is tantamount to escalating expenses using the O&M input price index in formula [1]. Formula [1] reveals that this approach is reasonable to the extent that expected O&M productivity growth equals expected customer growth. Research over the years has shown that productivity growth is similar to customer growth (and typically a little slower) and this has been acknowledged by the California Public Utilities Commission.

Consider, now, that it can be shown that the trend in the O&M expenses covered by the proposed RAM (which exclude pension expenses) is a cost-share weighted average of the trends in salary and wage expenses and material and service expenses. The trend in *each* expense category can be explained using a formula like [1]. This provides the basis for an alternative and more complicated RAM formula:

$$\begin{aligned} &\text{trend Cost}^{O\&M} \\ &= SC^{S\&W} \text{ x trend Cost}^{S\&W} + SC^{M\&S} \text{ x trend Cost}^{M\&S} \\ &= SC^{S\&W} \text{ x (trend Prices}^{S\&W} - \text{trend Productivity}^{S\&W} + \text{trend Customers}) + \\ &\quad SC^{M\&S} \text{ x (trend Prices}^{M\&S} - \text{trend Productivity}^{M\&S} + \text{trend Customers}) \qquad [2] \end{aligned}$$

where $SC^{S\&W \text{ and}}$ $SC^{M\&S}$ denote the cost shares of salaries and wages and materials and services.

Suppose, now, that we use the GDPPI to measure M&S input price inflation instead of an M&S input price index. We can revise formula [2] to accommodate this further complication as follows.

$$\begin{aligned}
&\text{trend Cost}^{O\&M} \\
&= SC^{S\&W} \times (\text{trend Prices}^{S\&W} - \text{trend Productivity}^{S\&W} + \text{trend Customers}) + \\
&\quad SC^{M\&S} \times \{\text{trend GDPPI} \\
&\quad - [\text{trend Productivity}^{M\&S} + (\text{trend GDPPI} - \text{trend Prices}^{M\&S})] \\
&\qquad + \text{trend Customers})\} \qquad [3]
\end{aligned}$$

There is now an additional term, called the "inflation differential," in the escalator for M&S expenses to adjust for any tendency of the GDPPI to under- or overestimate the trend in input prices.[2]

It will prove useful in the analysis that follows to restate formula [3] as

$$\begin{aligned}
&\text{trend Cost}^{O\&M} \\
&= SC^{S\&W} \times \text{trend Prices}^{S\&W} + SC^{M\&S} \times \text{trend GDPPI} \\
&\quad - SC^{M\&S} \times (\text{trend GDPPI} - \text{trend Prices}^{M\&S}) \\
&\quad - (SC^{S\&W} \times \text{trend Productivity}^{S\&W} + SC^{M\&S} \times \text{trend Productivity}^{M\&S}) \\
&\quad + (SC^{S\&W} + SC^{M\&S})\ \text{trend Customers} \\
&= SC^{S\&W} \times \text{trend Prices}^{S\&W} + SC^{M\&S} \times \text{trend GDPPI} \\
&\quad - SC^{M\&S} \times (\text{trend GDPPI} - \text{trend Prices}^{M\&S}) \\
&\quad - \text{trend Productivity}^{O\&M} + \text{trend Customers}. \qquad [4]
\end{aligned}$$

Here the two productivity trends have been consolidated into one, as can be supported by index logic.

The final SOP of the joint parties effectively uses the following escalation formula for O&M expenses:

$$\begin{aligned}
&\text{trend Cost}^{O\&M} \\
&= SC^{S\&W} \times (\text{trend Prices}^{S\&W} - 0.76) + SC^{M\&S} \times \text{trend GDPPI}. \qquad [5]
\end{aligned}$$

Comparing this formula to formula [3], it can be seen that there is no X factor for M&S expenses, no inflation differential to correct for the possible inaccuracy of the GDPPI, and no allowances for customer growth.

[2] The 0.76% X factor in the 1999 testimony also had an inflation adjustment.

The final SOP formula is exactly compensatory provided that [5] = [4]. That is

$$SC^{S\&W} \times (\text{trend Prices}^{S\&W} - .76) + SC^{M\&S} \times \text{trend GDPPI}$$
$$= SC^{S\&W} \times \text{trend Prices}^{S\&W} + SC^{M\&S} \times \text{trend GDPPI}$$
$$- SC^{M\&S} \times (\text{trend GDPPI} - \text{trend Prices}^{M\&S})$$
$$- \text{trend Productivity}^{O\&M} + \text{trend Customers}.$$

Rearranging terms, we require that

$$.76 = (1/SC^{S\&W}) \times [\text{trend Productivity}^{O\&M} + SC^{M\&S} \times (\text{trend GDPPI} - \text{trend Prices}^{M\&S}) - \text{trend Customers}].$$

The right hand side of the equation may be called the "X factor calibration formula." It shows that X factor in the salaries and wages ("S&W") escalator must reflect not simply the productivity of labor but the productivity of *all* O&M inputs, as well as the inaccuracy of the GDDPPI as a measure of input price inflation and the fact that there is no explicit adjustment for customer growth. Moreover, adjustments for these other conditions must be magnified to reflect the fact that the X only applies to salaries and wages.

Research by PEG which is reported in their February 3 revised report in this proceeding provided numbers useful in making the X factor calibration formula operational.

Over the 1996-2007 period, the customer growth of HECO, HELCO and MECO averaged 0.8%, 2.5%, and 1.9% respectively.

PEG calculated the average trend in the productivity of non-fuel O&M inputs of 43 vertically integrated U.S. electric utilities. The sample was smaller than in the productivity study filed in earlier HECO testimony due in large measure to restructuring. The sample period was 1996-2006. The average annual productivity growth of the sampled utilities was reported on page 68 of the report to be 1.26%.

Table 7 of the report displays results of an exercise by PEG to compute *summary* M&S input price indexes for the three HECO Companies using the detailed utility input price indexes available from Global Insight, a respected public source. Recall that these are the same input price indexes that have been used to escalate O&M expenses in California on numerous occasions. The trends of the summary indexes for HECO, HELCO, and MECO over the simulation period (1996-2007) were 3.05%, 2.85%, and 2.69%, respectively. Differences in the trends are due to differences in the composition of M&S expenses amongst the three companies.

Table 8 reports that the trend in the GDPPI over the same sample period was 2.21%. The GDPPI thus had a pronounced tendency to underestimate growth in the prices of M&S inputs for all three companies.

Other research by PEG in support of the report found that the share of salaries and wages in the applicable O&M expenses over the simulation period averaged around 45%, 37%, and 41% for HECO, HELCO, and MECO respectively. M&S expenses thus account for well over half of the total, making the tendency of the GDPPI to understate M&S input price inflation more important.

Plugging the pertinent numbers into the calibration formula for HECO we find that

$$(1/0.45) \times [1.26 - .8 + .55 \times (2.21 - 3.05)]$$
$$= (1/0.45) \times [1.26 - .8 + .55 \times (-.84)]$$
$$= -.00.$$

The analogous computation for HELCO is

$$(1/0.37) \times [1.26 - 2.5 + .63 \times (2.21 - 2.85)]$$
$$= (1/0.37) \times [1.26 - 2.5 + .63 \times (-.64)]$$
$$= -4.44.$$

The analogous computation for MECO is

$$(1/0.41) \times [1.26 - 1.9 + .59 \times (2.21 - 2.69)]$$
$$= (1/0.41) \times [1.26 - 1.9 + .55 \times (-0.48)]$$
$$= -2.25.$$

The calculations reveal that the 0.76% X factor in the S&W escalator is too high for HECO by about 76 basis points. The final SOP escalator would therefore probably have been uncompensatory for HECO in an application to the simulation period. Results are even worse for HELCO and MECO because the proposed escalator doesn't account for their rapid customer growth. While the numbers for HELCO and MECO particularly may be surprising, it should be remembered that the X factor applies only to the S&W escalator and that S&W expenses account for less than half of the total. It follows that the 0.76 X factor would have involved sizable implicit "stretch" factors for the HECO Companies. This finding is not surprising considering that the 0.76 X factor was the outcome of a settlement with Hawaii's Consumer Advocate.

To provide further evidence on the reasonableness of the final SOP O&M escalator, we simulated the results of using the escalator over the simulation period and compared them to the results for the alternative O&M escalators that were reported in Table 9 of the February 3 report. Results can be found in Attachment 2 to this response. It can be seen that the final SOP escalator was one of the least compensatory of all the mechanisms considered in the study. It was especially uncompensatory for HELCO and MECO, as we might expect.[3]

The following conclusions may be drawn from this research. The O&M escalator proposed in the final SOP RAM of the joint parties is similar to the many that have been approved for hybrid RAMs in *not* having the classic structure suggested by index theory. Index research can nonetheless be used to appraise its reasonableness. Research using indexing and other methodologies suggests that the proposed O&M escalator would have been uncompensatory to the HECO Companies during the simulation period.

[3] The Attachment also shows that a *cost per customer freeze* such as that which effectively results from Haiku Design and Analysis' proposed revenue per customer RAM would have been highly uncompensatory on average for the companies.

FINANCIAL SUFFICIENCY SIMULATION: SUMMARY OF HYBRID O&M SUFFICIENCY

	HECO		HELCO		MECO		All Company Total	
	Average Revenue Surplus (Shortfall) [1] [A]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [1] [B]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [1] [C]	Average Revenue / Cost [1]	Average Revenue Surplus (Shortfall) [A]+[B]+[C]	Average Revenue / Cost [1]
Hybrid I (PEG Custom Input Price Index)								
3 yr	(2,776,165)	0.987	(392,540)	1.002	(673,064)	0.996	(3,841,769)	0.995
4 yr	4,741,287	1.048	(2,226,910)	0.946	(1,757,333)	0.960	757,044	0.984
Average	**1,203,662**	**1.019**	**(1,363,677)**	**0.972**	**(1,247,089)**	**0.977**	**(1,407,103)**	**0.989**
Hybrid II (PEG 3 Category Decomposition)								
3 yr	(2,754,553)	0.987	(383,378)	1.003	(669,153)	0.996	(3,807,084)	0.995
4 yr	4,735,816	1.048	(2,210,164)	0.946	(1,753,940)	0.960	771,712	0.985
Average	**1,210,936**	**1.019**	**(1,350,500)**	**0.973**	**(1,243,452)**	**0.977**	**(1,383,016)**	**0.990**
Hybrid III (Full Indexation Using PEG Custom Input Price Index)								
3 yr	(3,734,844)	0.979	344,838	1.021	(317,536)	1.006	(3,707,542)	1.002
4 yr	3,477,826	1.038	(1,356,728)	0.967	(1,368,777)	0.969	752,321	0.991
Average	**83,628**	**1.010**	**(555,991)**	**0.992**	**(874,075)**	**0.986**	**(1,346,438)**	**0.996**
Hybrid IV (GDPPI)								
3 yr	(4,796,431)	0.971	(866,151)	0.989	(1,099,055)	0.984	(6,761,638)	0.981
4 yr	2,008,485	1.026	(2,861,174)	0.929	(2,381,572)	0.942	(3,234,261)	0.966
Average	**(1,193,828)**	**1.000**	**(1,922,340)**	**0.957**	**(1,778,035)**	**0.962**	**(4,894,203)**	**0.973**
Hybrid V (CPI-U Honolulu)								
3 yr	(3,935,594)	0.974	(635,274)	0.991	(910,013)	0.986	(5,480,881)	0.984
4 yr	2,124,976	1.023	(2,798,426)	0.926	(2,346,533)	0.940	(3,019,984)	0.963
Average	**(727,057)**	**1.000**	**(1,780,472)**	**0.957**	**(1,670,524)**	**0.962**	**(4,178,053)**	**0.973**
Hybrid VI (Global Insight's Summary Electric Utility Materials and Services Price Index [JETOTALMS])								
3 yr	(3,056,535)	0.983	(390,972)	1.001	(629,348)	0.996	(4,076,856)	0.993
4 yr	4,078,414	1.040	(2,316,111)	0.942	(1,833,072)	0.956	(70,769)	0.979
Average	**720,791**	**1.013**	**(1,410,163)**	**0.970**	**(1,266,614)**	**0.975**	**(1,955,986)**	**0.986**
Hybrid VII (HECO's 12 Category Decomposition)								
3 yr	(2,673,010)	0.988	(339,359)	1.004	(577,291)	0.999	(3,589,659)	0.997
4 yr	4,854,095	1.049	(2,153,931)	0.948	(1,650,724)	0.962	1,049,440	0.986
Average	**1,311,928**	**1.020**	**(1,300,015)**	**0.974**	**(1,145,579)**	**0.980**	**(1,133,667)**	**0.991**
Hybrid VIII (O&M Cost per Customer Freeze)								
3 yr	(7,707,148)	0.950	(697,476)	0.993	(1,299,604)	0.979	(9,704,229)	0.974
4 yr	(1,888,133)	0.998	(2,706,747)	0.932	(2,671,027)	0.936	(7,265,907)	0.955
Average	**(4,626,493)**	**0.975**	**(1,761,208)**	**0.961**	**(2,025,652)**	**0.956**	**(8,413,353)**	**0.964**
Hybrid IX (Final Statement of Position Escalator)								
3 yr	(4,920,669)	0.970	(898,000)	0.988	(1,130,077)	0.983	(6,948,747)	0.981
4 yr	1,581,068	1.024	(2,965,458)	0.926	(2,495,373)	0.940	(3,879,762)	0.963
Average	**(1,478,573)**	**0.998**	**(1,992,536)**	**0.955**	**(1,852,881)**	**0.960**	**(5,323,990)**	**0.971**

[1] Calculations cover only the out (i.e. attrition) years of decoupling plans.

PUC-IR-58

Should the RAM concepts described at 3a and b be based on gross or net plant additions?

HECO Companies Response:

The joint proposal submitted by the HECO Companies and the Consumer Advocate reflected a RAM based on a net increase in rate base concept (plant in service and plant additions, less depreciation accrual, contributions in aid of construction received and the impact of accumulated deferred income taxes on such plant additions). The RAM developed as suggested in information request 3a and b (responses to PUC-IR-52 a and b, revised August 13, 2009), was also based on net plant additions (plant additions, less depreciation accrual, contributions in aid of construction received net of amortization of contributions in aid of construction and the impact of accumulated deferred income taxes.) A RAM based on net plant additions (plant additions less depreciation accrual, contributions in aid of construction received net of amortization of contributions in aid of construction, and the impact on accumulated deferred income taxes) is reasonable as it is consistent with determining rate base under traditional ratemaking.

PUC-IR-59

Please propose allocation methods for among customer classes for each 3a, b, c, and d and explain the basis for the allocation.

HECO Companies Response:

In the interest of regulatory simplicity and keeping in mind the comparatively brief terms (2 and 3 years) of the proposed decoupling plans, the allocation of revenue requirement escalations should not be complicated between rate cases. The HECO Companies propose that escalations from the operation of options 3a, 3b, 3c, and 3d be allocated to customer service classes in the manner detailed in Section B titled, "TARGET REVENUE" in Exhibit A ("Revenue Balancing Account Provision") of the Final Joint Statement of Position filed by the Consumer Advocate and the HECO Companies on May 11, 2009. The target revenue, which will include the revenue adjustment provision, would be allocated to a residential customer class and a nonresidential customer class (commercial and industrial customers).

PUC-IR-60

What should the Commission consider in selecting an ROE to use in calculating revenue enhancements between rate cases associated with rate base changes. Why should the ROE used in calculating the interrate case revenue adjustments based on rate base changes be equal to the ROE authorized in the rate case (per the proposed RAM), as the interrate case ROE appears to be guaranteed and the rate case ROE is an opportunity to earn the authorized return? Please discuss and quantify.

HECO Companies Response:

In the Hawaiian Electric Company, Inc., 2009 test year rate case, Docket No. 2008-0083 (HECO 2009 Rate Case), HECO T-19, pages 9-13, Dr. Roger Morin discusses how a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. On pages 10-11 of his testimony, Dr. Morin states:

> The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:
>
> 1. Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).
>
> 2. Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944).
>
> The Bluefield case set the standard against which just and reasonable rates of return are measured:
>
> *A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties ... The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to*

> *maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.* (Emphasis added)
>
> The Hope case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the Bluefield case and recognized that revenues must cover "capital costs." The Court stated:
>
> *From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock ... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.* (Emphasis added)
>
> The United States Supreme Court reiterated the criteria set forth in Hope in Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), in Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Company vs. Barasch, 488 U.S. 299 (1989). In the Permian cases, the Supreme Court stressed that a regulatory agency's rate of return order should:
>
> *...reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed...*
>
> Therefore, the "end result" of this Commission's decision should be to allow HECO the opportunity to earn a ROE that is:
> (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the Company's financial integrity, and (3) sufficient to maintain the Company's creditworthiness and ability to attract capital on reasonable terms.

This requirement is not limited to only the rate base that is reviewed in the rate case for the test year but should also apply to the Companies' rate bases between rate cases. The primary reason why the budget that underlies a forward-looking test year is adjusted and normalized is to make the test year results of operation more representative of a normal, on-going level of operations, or of the operating conditions that are expected to be in effect during the period that the rates will be in effect. The specific ROE, like other costs, is thus anticipated to be commensurate with the returns that investors expect from investments with similar risk attributes as the Companies during the time that rates are in effect. Given the short periods between rate cases proposed in the instant docket by the Consumer Advocate and the HECO Companies, the ROE established by the Commission in the individual rate cases should also apply between rate cases.

The interrate case ROE is an opportunity to earn the authorized return consistent with the rate case ROE. Under the proposals being considered, the interrate case rate of return on equity is not guaranteed. For example, (1) there are numerous items in rate base that are not covered by the interrate case adjustment which can result in the actual ROE being lower than the authorized ROE, and (2) under the proposed sales decoupling mechanism, the target revenues are based on an escalated test year revenue requirement and not on actual costs that are incurred during the interrate case period. The ROE deemed fair and reasonable in future rate cases would take into consideration the existence of a RAM adjustment and any interrate case revenue adjustments accordingly. In the current HECO 2009 Rate Case, Dr. Morin (HECO RT-19) also indicates that it is currently speculative as to whether, and if so how, decoupling and the RAM will affect the Hawaiian Electric's risk profile. He recommends a range of 11.0%-11.25% assuming the Consumer Advocate's and the HECO Companies' decoupling and RAM proposal is approved, and a range of 11.25%-11.5% otherwise. (See HECO RT-19, p. 68.)

In recognition that ROEs may fluctuate during the period between rate cases due to earnings and changing rate base values, the Consumer Advocate and the HECO Companies have proposed the establishment of Earnings Sharing Revenue Credits that ensure that customers also benefit from any earnings experienced by the Companies' shareholders above the authorized ROE. These are amounts that will be returned to customers as credits through the Revenue Balancing Account (RBA) Provision so as to implement the earnings sharing percentages and procedures described in the RAM Provision. Discussion regarding the Earnings Sharing Revenue Credits is found on pages 18 to 20, page 5 of Exhibit B, filed in the Joint Final Statement of Position of the HECO Companies and the Consumer Advocate on May 11, 2009. Exhibit B, the RAM Provision, was subsequently revised and submitted as Attachment 7 to the HECO Companies letter to the Commission, dated July 13, 2009, with subject "Questions from Panel Hearings Held on June 29, to July 1, 2009".

PUC-IR-61

Please discuss the pros and cons of the Commission approving a RAM that consists of 3a, b[,] and c with and without an RPC compared to the RAM proposed by HECO.

HECO Companies Response:

Attachment 1 (confidential) of this response, pages 1 and 2, presents the returns on common equity ("ROE") and the RAM amounts associated with 3a, b, and c with and without an "RPC with reset" as compared to the RAM amounts proposed by the Consumer Advocate and HECO Companies in their Final Joint Statement of Position filed May 11, 2009, which include calculated rate base RAMs and the O&M expense RAMs ("JSOP RAM"). As Attachment 1 includes financial information for future years which is nonpublic information that should not be disclosed publicly as it might trigger requirements under the rules and guidelines of the Securities and Exchange Commission and/or the New York Stock Exchange that information that would be meaningful to investors be released to all investors, if the information is disclosed beyond a limited number of "insiders" (including persons required by agreement to maintain the confidentiality of the information and to use it only for proper purposes), it is being filed under the Protective Order issued on January 6, 2009 in this proceeding. If Attachment 1 is not filed under the Protective Order in this proceeding, the disclosure of nonpublic financial information might trigger disclosure requirements under the rules and regulations of the Securities and Exchange Commission and/or the New York Stock Exchange.

Before discussing the comparisons shown in Attachment 1, it is worthwhile to reiterate some qualifications regarding the Companies' calculation approach so that as the comparisons can be viewed from an appropriate perspective. The Companies' original response to PUC-IR-52, filed August 7, 2009, item 3 on page 4, stated:

3) As the original PUC-IR-14 requested historical results for 2004 to 2008 without backcasting for sales decoupling and the inclusion of RAM revenues, the original results did not include the effect of the implementation of sales decoupling for the historical years (as well as for the prospective years before the assumed year where sales decoupling is effective). Since NRRI stated that the IR was intended to analyze the change based on the system reliability and customer additions RAM methodologies proposed in the IR, it was not necessary to derive the sales decoupling component for the historical years to respond to subparts a and b. See the note on Attachment 8, pages 1 and 2, which further explains the impact of the exclusion of the sale decoupling ("RBA") component.

Attachment 8 in the original PUC-IR-52 response, note 1, stated:[1]

> Note 1 "...NRRI agreed to use the historical recorded or projected earnings as shown on Attachment 1, without calculating and incorporating the sales decoupling adjustment. Where there was sales growth in the historical/projected years as shown on Attachment 1, these ROE percentages are overstated as the historical/projected earnings shown on Attachment 1, line 22, would have included the additional revenue and earnings from the sales growth. The reverse is true for the historical/projected years when there is a sales decline, as these ROE percentages are understated from not having adjusted revenue and earnings for the short fall in sales..."

In addition to the above, the Companies also provided work papers in their revised response to PUC-IR-52, filed August 13, 2009, to support the average common equity calculations under the NRRI's proposed revenue adjustments scenario. Because of the backcasting of the proposed NRRI's revenue adjustments to historical years, HECO's and HELCO's 2011 ROE comparison results are further explained in the footnotes 2, 3, and 4 which follows.

The key assumptions used by the Companies for the JSOP rate base RAM and NRRI system reliability and customer addition RAMs (i.e., the 3a and 3b RAMs) should also be reiterated before discussing the Attachment 1 comparisons. The JSOP rate base RAM is the sum of a baseline component, calculated based on a historical five-year average without adjustment

[1] Attachment 1 in these two notes refers to the Attachment 1 in the Companies' original response to PUC-IR-52, filed August 7, 2009.

for inflation, plus a major project component, calculated based on an amount not to exceed the authorized amount for major projects which estimated to be placed into service in the first nine months of the RAM year. The full cost of major projects are not included in the JSOP rate base RAM until the following year. In the NRRI system reliability and customer addition RAM calculations, a key assumption is that most of the plant addition amounts are classified as system reliability projects, and that the full costs of the system reliability additions are reflected in the quarter following the in-service date of the additions. Further, in the revised response to PUC-IR-52 filed August 13, 2009, the HECO Companies reflected only one-half of the calculated system reliability and customer addition RAMs to (1) account for projects which might be placed in service in the second half of the year, and (2) more closely approximate the quarterly mechanism as requested in PUC-IR-52. Using HECO's 2010 as an example, the JSOP rate base RAM is $24,172,000[2], and the NRRI system reliability RAM is $14,793,000.

In general, as shown in Attachment 1, page 1 to this response, as expected, the differences between the ROEs associated with 3a, b, and c **with** an "RPC with reset" are much higher than the differences **without** an "RPC with reset" when compared to the ROEs resulting from the JSOP RAMs. Of note, even the 3a, b, and c without "RPC with reset" option results in ROEs that are mostly higher than the ROEs calculated for the JSOP RAM for the HECO Companies which is a "pro" for the Companies.

Two exceptions to this were noted. In 2010, the JSOP RAM resulted in a higher ROE for HECO than the 3a, b, and c, with and without the "RPC with reset" option by 16 and 36 basis points, respectively. For HELCO in 2011, the JSOP RAM resulted in a higher ROE than the 3a,

[2] The $24,172,000 amount is part of the $29,453,000 shown in the Companies' response to PUC-IR-14, revised 6/29/09, Attachment 1, page 1, line 31, column G. The remaining balance of $5,281,000 is the JSOP O&M RAM (see response to PUC-IR-52, filed 8/7/09, Attachment 7).

b, c, with and without the "RPC with reset" option by 25 and 51 basis points, respectively. Both of these exceptions were impacted by the assumption used (discussed above) that for the first year that the 3a, b, c, with and without the "RPC with reset" option is implemented, only the first two quarters (50%) of this RAM would be reflected since data regarding plant additions put into service in the first quarter of the year (January through March) would need to be processed and submitted to the Commission for RAM recovery that would begin no sooner than the beginning of the third quarter (September)[3], [4].

In order to remove the impact that differences in average common equity balances could have on ROE calculations, page 2 of Attachment 1 provides a comparison of the revenue change due to the JSOP RAM versus the revenue change for the NRRI 3a, b, and c RAM with and without the "RPC with reset". With the exception of HECO's 2010 and HELCO's 2011 results, the revenue adjustments from NRRI's RAM are higher than the JSOP RAM.[5]

As stated in the Companies' narrative response to PUC-IR-52, pages 5 to 6, the primary advantage of the 3a and 3b options is that, by being based only on plant amounts that are actually placed into service, they address the Commission's concern regarding customers paying for investments that have not actually been placed into service. Although the JSOP RAM uses a five-year historical average for "baseline" plant additions, i.e., plant additions that individually cost less than $2.5M and were not required to be filed for approval as required by G.O.7[6], major projects with forecasted in-service dates from January through September of the RAM year were

[3] Further discussion regarding the recovery assumptions used for the 3a and b options are found in the Companies' narrative response to PUC-IR-52, pages 12-13, revised 8/13/2009.
[4] For HELCO's 2011 ROE comparison result, another contributing factor is the increase in average common equity for 2011 due to the backcasting of NRRI's RAM to the historical (2004 to 2008) and prospective years (2009-2013). As HELCO's first rate case was assumed to be in 2010, with sales decoupling effective in 2011, the backcasting affected 2009 and 2010 results as well.
[5] See footnotes 2 and 3.
[6] Plant additions that individually cost more than $2.5M and are required to be filed for approval as required by G.O.7 were defined as "major projects".

included in the calculation of the RAM. A disadvantage of the 3a and 3b options is that the actual in-service costs are included in the calculation of the RAM which may result in the inclusion of cost overruns for major projects. The Companies noted in their original response to PUC-IR-52 that this concern can be addressed by limiting the plant addition amounts for the major projects to their authorized amounts, similar to what is used in the JSOP RAM calculation.

Additionally, both the 3a, b, c, with and without the "RPC with reset" option implementation involves considerably higher regulatory cost than the JSOP RAM. The JSOP RAM is proposed to be filed once a year while implementation of any one of more of the NRRI options will require quarterly filings. With every filing, regardless of the magnitude of the amounts involved, a considerable amount of the Companies' resources will be required to prepare the filing as well as to respond to questions raised by the Commission, the Consumer Advocate or other parties. The Consumer Advocate and the Commission will be required to review filings, at a minimum, four times a year as well.

Comparison of NRRI's Proposed Revenue Enhancements/RAMS with Joint Proposal
With RPC with Reset
Summary of ROE's

			2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
I. With RPC with Reset								[redacted]				
HECO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a	[redacted]				
	52a, b, & c	(2)	**9.80%**	**9.04%**	**9.18%**	**7.05%**	**8.85%**	[redacted]				
	Difference		n/a	n/a	n/a	n/a	n/a	[redacted]				
HELCO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a	[redacted]				
	52a, b, & c	(2)	**10.31%**	**14.54%**	**14.28%**	**9.55%**	**8.64%**	[redacted]				
	Difference		n/a	n/a	n/a	n/a	n/a	[redacted]				
MECO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a	[redacted]				
	52a, b, & c	(2)	**11.76%**	**12.52%**	**15.67%**	**14.48%**	**9.91%**	[redacted]				
	Difference		n/a	n/a	n/a	n/a	n/a	[redacted]				
II. Without RPC with Reset								[redacted]				
HECO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a	[redacted]				
	52a, b, & c	(3)	**9.75%**	**8.81%**	**8.86%**	**6.68%**	**8.78%**	[redacted]				
	Difference		n/a	n/a	n/a	n/a	n/a	[redacted]				
HELCO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a	[redacted]				
	52a, b, & c	(3)	**9.61%**	**13.18%**	**12.40%**	**9.24%**	**8.46%**	[redacted]				
	Difference		n/a	n/a	n/a	n/a	n/a	[redacted]				
MECO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a	[redacted]				
	52a, b, & c	(3)	**11.20%**	**11.42%**	**14.03%**	**12.43%**	**9.21%**	[redacted]				
	Difference		n/a	n/a	n/a	n/a	n/a	[redacted]				

Note:

(1) See HECO Companies response to PUC-IR-52, revised 8/13/09, Attachment 1, pages 1-3, line 33b for the ROEs associated with the Joint Proposal RB and O&M RAM.

(2) See HECO Companies response to PUC-IR-52, revised 8/13/09, Attachment 1, pages 1-3, line 87 for the ROEs associated with the 3a, b, c, with RPC option (noted as 52e).

(3) See HECO Companies response to PUC-IR-52, revised 8/13/09, Attachment 1, pages 1-3, line 127 for the ROEs associated with the 3a, b, c, without RPC option (noted as 52e).

(4) The HECO Companies' PUC-IR-14 filing (revised 6/29/09 for HECO and HELCO, 6/25/09 for MECO) included the effect of the sales decoupling component (i.e. the revenue balancing account ("RBA") only for the prospective years after the test year rate cases where sales decoupling and the RBA were assumed to have been approved by the Commission. These prospective years would be 2010 to 2013 for HECO, and 2011 to 2013 for HELCO and MECO (shaded). To simplify the calculations for the NRRI RAMs, NRRI agreed to use the historical recorded or projected earnings as shown on Attachment 1, line 22, in response to PUC-IR-52, without calculating and incorporating the sales decoupling adjustment. Where there was sales growth in the historical/projected years as shown on Attachment 1, line 136, in response to PUC-IR-52, these ROE percentages are overstated as the historical/projected earnings shown on Attachment 1, line 22, PUC-IR-52, would have included the additional revenue and earnings from the sales growth. The reverse is true for the historical/projected years when there is a sales decline, as these ROE percentages are understated from not having adjusted revenue and earnings for the shortfall in sales.
See the narrative response to PUC-IR-52, item 3, for additional details and discussion.

Confidential Information Deleted Pursuant To Protective Order, Filed on January 6, 2009.

Comparison of NRRI's Proposed Revenue Enhancements/RAMS with Joint Proposal
With RPC with Reset
Summary of ROE's

Figures in ($1,000s)

			2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
I. With RPC with Reset												
HECO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a	[redacted]				
	52a, b, & c	(2)	$ 11,483	$ 25,467	$ 13,319	$ 27,570	$ 7,802					
	Difference		n/a	n/a	n/a	n/a	n/a					
HELCO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a					
	52a, b, & c	(2)	$ 11,397	$ 29,751	$ 42,973	$ 13,309	$ 5,826					
	Difference		n/a	n/a	n/a	n/a	n/a					
MECO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a					
	52a, b, & c	(2)	$ 3,818	$ 9,448	$ 19,878	$ 30,820	$ 5,408					
	Difference		n/a	n/a	n/a	n/a	n/a					
II. Without RPC with Reset												
HECO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a					
	52a, b, & c	(3)	$ 10,889	$ 22,794	$ 9,732	$ 23,252	$ 6,895					
	Difference		n/a	n/a	n/a	n/a	n/a					
HELCO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a					
	52a, b, & c	(3)	$ 8,978	$ 24,107	$ 34,104	$ 10,286	$ 3,173					
	Difference		n/a	n/a	n/a	n/a	n/a					
MECO	Joint Proposal RB and O&M RAM	(1)	n/a	n/a	n/a	n/a	n/a					
	52a, b, & c	(3)	$ 1,920	$ 5,652	$ 14,184	$ 23,456	$ 2,739					
	Difference		n/a	n/a	n/a	n/a	n/a					

Note:

(1) See HECO Companies response to PUC-IR-52, Attachment 1, revised 8/13/09, pages 1-3, line 31 for the ROEs associated with the Joint Proposal RB and O&M RAM.

(2) See HECO Companies response to PUC-IR-52, Attachment 1, revised 8/13/09, pages 1-3, line 55 for the ROEs associated with the 3a, b, c, with RPC option (noted as 52e).

(3) See HECO Companies response to PUC-IR-52, revised 8/13/09, Attachment 1, pages 1-3, line 95 for the ROEs associated with the 3a, b, c, without RPC option (noted as 52e).

(4) The HECO Companies' PUC-IR-14 filing (revised 6/29/09 for HECO and HELCO, 6/25/09 for MECO) included the effect of the sales decoupling component (i.e. the revenue balancing account ("RBA") only for the prospective years after the test year rate cases where sales decoupling and the RBA were assumed to have been approved by the Commission. These prospective years would be 2010 to 2013 for HECO, and 2011 to 2013 for HELCO and MECO (shaded). To simplify the calculations for the NRRI RAMs, NRRI agreed to use the historical recorded or projected earnings as shown on Attachment 1, line 22, in response to PUC-IR-52, without calculating and incorporating the sales decoupling adjustment. Where there was sales growth in the historical/projected years as shown on Attachment 1, line 136, in response to PUC-IR-52, these ROE percentages are overstated as the historical/projected earnings shown on Attachment 1, line 22, PUC-IR-52, would have included the additional revenue and earnings from the sales growth. The reverse is true for the historical/projected years when there is a sales decline, as these ROE percentages are understated from not having adjusted revenue and earnings for the shortfall in sales.
See the narrative response to PUC-IR-52, item 3, for additional details and discussion.

PUC-IR-62

Please discuss the pros and cons of an ECAC in which (a) the utility bears the risk for heat rate changes within a performance band (e.g., plus/minus 50 Btu from the target) while (b) all changes in costs associated with heat rate changes outside the performance band are passed through to customers.

HECO Companies Response:

The hypothetical structure contemplated by this information request contrasts with the joint HECO Companies (HECO, HELCO and MECO, collectively) and Consumer Advocate "ECAC Deadband Proposal" submitted in this proceeding on June 25, 2009, in Exhibit C, Attachment 7. In the former, there is a performance band within which the utility bears the risk for changes in heat rate and outside of the performance band the costs associated with changes in heat rate are passed on to customers. In the latter (joint HECO Companies-Consumer Advocate deadband proposal), it is the opposite where there is a deadband within which the costs associated with changes in heat rate are passed on to customers and outside of the deadband the utility bears the risk for changes in heat rate. For the purposes of this response, the former will be referred to as the "performance band concept" and the latter will be referred to as the "deadband concept."

In the first technical workshop, Haiku Design and Analysis ("HDA") raised the issue that the fixed heat rate could result in the utilities recovering more or less than their fixed costs under sales decoupling and that the fixed heat rate may incent the utilities to take less renewable energy under certain circumstances. As a result, HDA proposed that the ECAC be changed and the efficiency factor be eliminated with sales decoupling. This was supported by most of the other parties and in their Opening Statements of Position in this proceeding, the State of Hawaii Department of Business, Economic Development and Tourism, and Hawaii Renewable Energy Alliance along with HDA recommended that the efficiency factor be eliminated and the ECAC permit full pass through of fuel costs and in its Final Statement of Position, Blue Planet Foundation also supported an ECAC with full pass through of fuel costs.

In response, the joint proposal[1] included a provision to establish a heat rate deadband around the fixed heat rate within which there is a complete pass-through of fuel and purchased energy expenses which means that the utilities would more accurately recover their fixed costs under sales decoupling (when within the range of the upper and lower heat rate deadband). In addition, in the deadband concept, the HECO Companies and the Consumer Advocate jointly proposed provisions to allow the target heat rate (around which the deadband would apply) to be reset under various circumstances. Please refer to the Joint Statement of Position, Revised and New Exhibits, filed on June 25, 2009 in this proceeding, Exhibit C, Attachment 7, Section C, pages 3 to 6.

However, under the performance band concept the utility bears the risk for heat rate changes within a performance band (e.g., plus/minus 50 Btu from the target)and the impact of the fixed heat rate on the recovery of fixed costs under sales decoupling is not addressed. The fixed heat rate would remain in place within the performance band of plus/minus 50 Btu from the target. Only when the actual heat rate varies more than 50 Btu from the target would a pass-through be effected. However, since the pass-through would only apply to expenses resulting from a heat rate more than 50 Btus higher and lower than the target (but not within 50 Btus of the target) the ECAC revenue plus base fuel energy charge revenue will never be representative of variable fuel and purchased energy expense. In effect, under this mechanism,

[1] See Joint Final Statement of Position of the HECO Companies and Consumer Advocate filed May 11, 2009, Exhibit D.

the sales decoupling mechanism the utilities would continue to recover more or less than their fixed costs.

The performance band mechanism described in this IR would partially remove the heat rate disincentive against additions of renewable energy that result in large variations from the fixed heat rate. For example, as indicated in the Revised and New Exhibits for the Joint SOP, dated June 25, 2009, Exhibit C, Attachment 7, page 3, section C., "...HECO projected that Maui Division's diesel system heat rate could increase by 282 Btu/kWh-net if a 21 MW windfarm is added to the Maui system and an additional 10.5 MW of regulating reserve is carried (over and above the existing 15 MW average amount of regulating reserve already carried)." Therefore, the utilities would be able to recover the additional fuel expenses associated with this example of additional renewable energy to the extent that the heat rate was more than 50 Btus higher than the fixed heat rate. It would still not be able to recover the additional fuel expenses related to a resulting heat rate that is between zero and 50 Btu/kwh higher than the fixed heat rate.

The performance band concept has two sets of efficiency incentives depending on the heat rate at which the utility is operating. First, if the utility is operating above the fixed heat rate it has an incentive to improve the efficiency of its operations (reduce the heat rate) because it recovers ECAC revenue at the fixed heat rate level. Even if the utility is operating above the 50 Btu deadband on the high side, where it is able to pass through all fuel expenses above the 50 Btu deadband threshold, it has a financial incentive to improve the efficiency of its operations because moving closer to the fixed heat rate reduces the fuel expenses that it cannot recover. As indicated above, this only partially removes the disincentive for renewable energy additions that increase the heat rate.

However, if the utility is operating below the fixed heat rate, it has an incentive to operate at the lower 50 Btu deadband threshold at which point it would maximize its financial gain. If it is operating within the lower deadband, the utility will have an incentive to move toward the lower deadband threshold because it gets to keep the savings. If the utility is operating below the deadband on the low side, it cannot improve its financial situation by improving its heat rate further (since all savings resulting from a heat rate being below the lower deadband threshold are passed to customers). Therefore, the utility could allow its heat rate to move toward the lower deadband threshold.

In today's business environment, at least three factors will have a negative impact on sales growth. These factors are the Hawaii Clean Energy Initiative ("Energy Agreement"), higher energy costs, and inclining block rates. (See Decoupling panel hearing transcripts, closing statement of Mr. Tom Williams, page 730, lines 3 to 10.) As shown in HECO's response to PUC-IR-53, pages 11 and 14, lower sales has the effect of increasing system heat rates for HELCO and MECO. Therefore, the utilities' pursuit of energy efficiency and conservation measures such as those described in the Energy Agreement and through inclining block rates may actually have a deleterious effect on their financial results under the performance band concept. This is because the lower sales are projected to increase system heat rates, which in turn will result in unrecoverable fuel costs to the utilities. This will produce a disincentive for the utilities to pursue measures that decrease its sales. In contrast, under the deadband concept, with the ability to reset the target heat rate and the related deadband, there would be no such disincentive because the amount of the increase in heat rate resulting from a decrease in sales is anticipated to be within the deadband and therefore, the costs associated with the higher heat rate could be passed on to customers.

PUC-IR-63

Please discuss the pros and cons of an ECAC that remained the same as the current ECAC but removed the Btus used for spinning reserve from the heat rate calculation.

<u>HECO Companies Response:</u>

First, all Btus generate electricity. Therefore, technically, it is impossible to "remove the Btus used for spinning reserve from the heat rate calculation."

Second, spinning reserve is not "generated." Spinning reserve is the amount of reserve capacity that is immediately available from units that are connected to the system and are operating below their maximum rated levels. Spinning reserve is the difference between the total amount of generating capacity connected to the system and operating and the total demand on the system. For example, if the total system demand is 100 MW and three 50 MW units are operating to serve this demand, the total amount of generation in operation is 150 MW. Only 100 MW of the three units' aggregate capacity are being used to serve the demand, and there are 50 MW of spinning reserve.

Third, regulating reserve is a subset of spinning reserve that responds to signals from automatic generator controls. In order to operate an electrical grid safely and reliably, supply (generation) and system demand must be kept in balance at all times (in addition to other considerations). Because demand on the system is constantly changing, some amount of regulating reserve is needed to maintain this balance. For example, if the demand on a system is 1,000 MW and exactly 1,000 MW of generation is serving the demand, then if demand suddenly increases by 10 MW, such as when a large industrial customer begins operations, there would not be enough generation immediately available to serve the increased demand. This would result in low frequency on the system and a possible interruption of service to customers since some circuits that serve customers may trip out of service on underfrequency. It would not be possible to operate the grid safely and reliably without some amount of spinning or regulating reserve.

Fourth, as indicated in its response to PUC-IR-53, the HECO, HELCO, and MECO systems cannot operate with zero spinning or regulating reserve. Because demand on the system is constantly changing, a reserve is needed to keep supply and demand in balance at all times. Without this reserve, the system would be subject to low frequency on the system and a possible interruption of service to customers. Moreover, there is always an inherent amount of reserve on the system because generation, when brought on line, comes on in large increments.

Fifth, as explained in HECO's response to PUC-IR-53, HECO operates its system with a given minimum level of spinning reserve that would cover for the loss of its largest operating unit. Typically, the largest operating unit on the HECO system is the AES 180 MW unit. HECO carries 180 MW of spinning reserve to maintain service to customers should the 180 MW unit unexpectedly trip out of service. HELCO and MECO do not operate with the same spinning reserve policy. As explained in HECO's response to PUC-IR-53, MECO-Maui Division and HELCO carry approximately 15 MW on average of regulating reserve to account for changes in demand and in the output of as-available energy generation.

In the operation of the grid with some given minimum level of spinning or regulating reserve, some amount of "extra" spinning reserve may be provided as a consequence of the particular system demand, the generating units available to serve the demand, and the sizes of the generating units. Take the example above where there are three 50 MW generating units available to serve a 100 MW system demand. Suppose, for illustrative purposes, that to keep supply and demand in balance at all times, only 20 MW of spinning reserve are required. In this case, all three 50 MW units must operate to serve the 100 MW of demand and provide 20 MW of spinning reserve. Since all three units are operating, there are actually 50 MW of spinning reserve available, even though only 20 MW are needed. Given the particular set of generating units, system demand, and spinning reserve needed, it is not possible to provide exactly 20 MW of spinning reserve. An additional 30 MW of "extra" spinning reserve is provided simply as a consequence of the circumstances. In the operation of an actual grid such as HECO's, this is usually the case where some amount of "extra" spinning reserve may exist because of the particular set of generating units, system demand, and spinning reserve needed.

Sixth, in order to operate with a given minimum level of spinning reserve or regulating reserve, units have to be "committed" (i.e., started up and synchronized to the grid) such that the total amount of generating capacity connected to the system and operating, minus the estimated total demand on the system, will equal or exceed the desired minimum amount of spinning reserve or regulating reserve. More Btus are required to generate the same amount of electricity as the minimum amount of spinning reserve or regulating reserve is increased. The "heat rate curve" for a typical 50 MW steam unit is shown on page 8 of this response. The heat rate (on the vertical axis) is a function of the load on the unit (horizontal axis). The heat rate curve for a unit is determined by measuring the rate of fuel consumption (in Btu per hour) at various load points across a unit's operable range then dividing the rate of fuel consumption by the load. In the example above with three 50 MW generating units serving 100 MW of demand, there are 50 MW of spinning reserve, even though only 20 MW are needed. If the three units are sharing load equally, then each unit will be operating at 33.33 MW and providing 16.66 MW of spinning reserve. The heat rate for each of the units based on the curve provided on page 8 of this response would be approximately 11,650 Btu/kWh-net. In this scenario, it is simple to determine the system heat rate. Since all units are operating at the same load point and have the same heat rate at that point, the system heat rate is approximately 11,650 Btu/kWh-net. This is the system heat rate that results from serving the 100 MW of demand <u>while simultaneously providing</u> the required 20 MW of spinning reserve and incidentally providing an "extra" 30 MW of spinning reserve. The fuel that is used to provide the spinning reserve is part and parcel of the fuel used to serve the demand. The fuel that is used to provide the spinning reserve cannot be separated from the fuel used to serve the demand.

Consider a more complex example where the system demand is still 100 MW and the spinning reserve requirement is still 20 MW but that the three units are not equally sized and their heat rate curves are all different. One example would be units sized at 40 MW, 50 MW and 60 MW. In this case, all three units still have to run to provide the necessary spinning reserve amount. Suppose further that the 60 MW unit is operating at 45 MW, providing 15 MW of spinning reserve, and its heat rate at that point is 10,500 Btu/kWh; the 50 MW unit is operating at 45 MW, providing 5 MW of spinning reserve, and its heat rate at that point is 9,000 Btu/kWh; and the 40 MW unit is operating at 10 MW, providing 30 MW of spinning reserve, and its heat rate at that point is 12,000 Btu/kWh. There would be a total of 50 MW, of which 30 MW would be "extra" spinning reserve over and above the 20 MW required. The 20 MW of required spinning reserve can be considered to be coming from any combination of the three operating units.

While the fuel consumption for each of the units can be determined, the fuel consumption associated with providing the 20 MW of required spinning reserve cannot be determined. This is because "extra" spinning reserve is provided incidentally with the provision of the required spinning reserve and the "extra" spinning reserve is indistinguishable from the required spinning reserve.

Furthermore, if the spinning reserve requirement is increased from 20 MW to 30 MW, there would be no extra cost associated with the requirement because the additional 10 MW of required spinning reserve would just come from the "extra" spinning reserve that is already being provided.

However, if the spinning reserve requirement is increased to 51 MW, then another unit (assuming it is available) would need to be turned on and the loads on the four operating units would need to be allocated economically. There may be extra costs associated with operating this additional unit just to provide the additional 1 MW of spinning reserve. This incremental cost can be determined from the difference in the total fuel cost to provide the higher amount of spinning reserve and the total fuel cost to provide the lower amount of spinning reserve.

Complicating the scenario even further, the demand on an electrical grid typically changes from minute to minute as customers turn equipment on and off. For a given amount of connected and operating generation, the total amount of spinning reserve available (required plus "extra") would change from minute to minute as demand changes (since spinning reserve is the difference between the total amount of generating capacity connected to the system and operating and the total demand on the system). Generally, the outputs of the running generating units would also change from minute to minute as the system demand is economically allocated among all the running generators.

There are 19 firm generating units on the HECO system. Sixteen are HECO units and three are independent power producer units. One of the independent power producer units

(Kalaeloa) actually consists of three separate generators. It can be seen how complex the spinning reserve issue can become with this number of generating units.

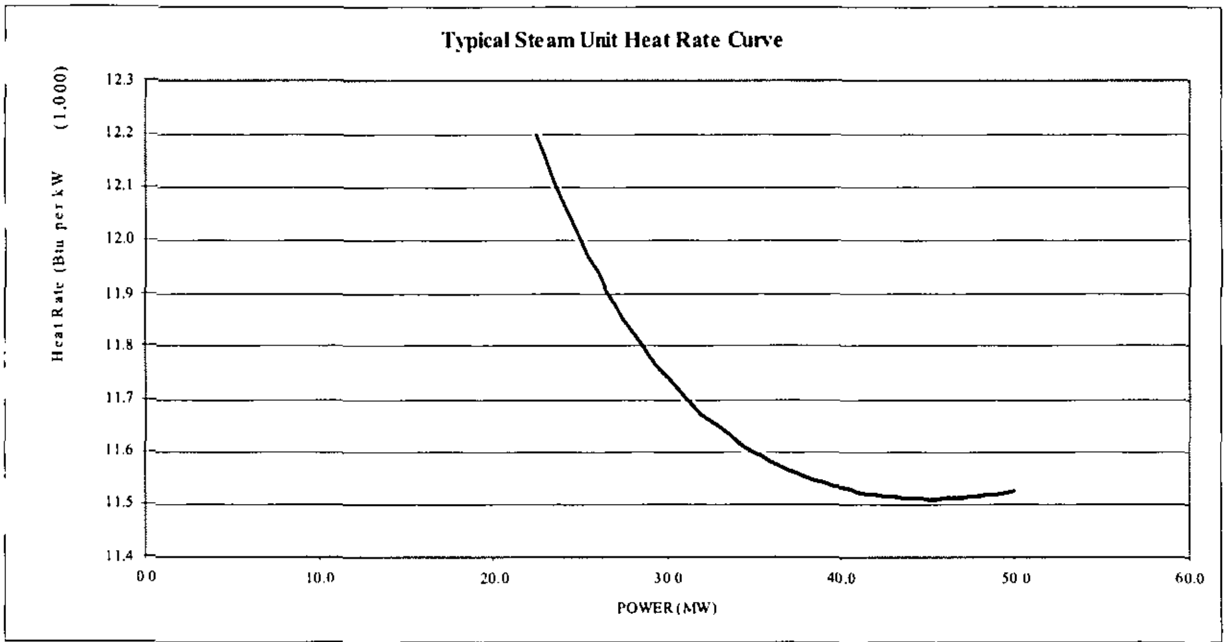
Seventh, theoretically, the difference in Btus between a system with a spinning reserve or regulating reserve policy, and the hypothetical minimum spinning or operating reserve that could be carried to meet load requirements could be calculated. However, the HECO Companies (HECO, HELCO and MECO, collectively) do not propose removing the amount of fuel (Btus) used for spinning reserve (even if it could be done) from the heat rate calculation for the purposes of determining the amount of fuel cost that would be recovered through the ECAC. The provision of spinning reserve as well as regulating reserve is an essential part of providing reliable service.

Moreover, such a calculation would not serve a useful purpose. One of the disadvantages to the hypothetical calculation of the fixed heat rate is that the ECAC and heat rate calculation would not reflect how the utilities operate the system and incur variable fuel expenses to ensure reliable service. Operating with spinning or regulating reserve improves service reliability but increases heat rate because more units need to be operating and each unit must operate at a lower output level where its fuel efficiency is lower.

The fuel expenses incurred as the result of operating with spinning or regulating reserve vary with energy (kWh) of generation and fuel prices and should be recovered through the ECAC as variable fuel costs. If these costs are not recovered through the ECAC, then they would have to be recovered through base rates and treated as fixed costs, which they are not. Recovery of these variable fuel costs as fixed costs implies that depending on the level of actual fuel prices, the utilities may recover more or less than actual costs through base rates.

The Companies currently reconcile ECAC revenues with actual fuel and purchased energy expenses every quarter. The quarterly reconciliations require that the actual Btus burned be compared to the Btus implied by the fixed heat rate. Therein lies another disadvantage of the hypothetical calculation of heat rate, which is that in order to perform the reconciliations the Companies would need to know how many Btus were burned to provide spinning or operating reserve and subtract those Btus from the total Btus burned. However, in its response to PUC-IR-53, the Companies explained that the effect of spinning or regulating reserve on heat rate cannot be isolated using historical data because so many variables that affect the heat are changing simultaneously.

In conclusion, the hypothetical calculation (as contemplated by this information request) of the fixed heat rate for rate case purposes does not represent the way the utilities operate their generating units to maintain reliability, contributes to the inaccurate recovery of fixed costs by recovering variable fuel expenses through base rates, and is impractical to implement because of the difficulty of isolating the impact of spinning or regulating reserve using calculations based on historical data. The HECO Companies have not been able to identify any advantages to the hypothetical calculation.


Typical Steam Unit Heat Rate Curve
Heat Rate (Btu per kW (1,000)
12.3
12.2
12.1
12.0
11.9
11.8
11.7
11.6
11.5
11.4
0.0
10.0
20.0
30.0
40.0
50.0
60.0
POWER (MW)